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Scenario-based security-constrained hydrothermal coordination with volatile wind power generation

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ABSTRACT

This paper presents the application of Mixed-Integer Programming (MIP) approach for solving the security-constrained daily hydrothermal generation Scheduling which takes into account the intermittency and volatility of wind power generation, which is called Security-Constrained Wind Hydrothermal Coordination (WHTC). In restructured power systems, Independent System Operators (ISOs) execute the Security-Constrained Unit Commitment (SCUC) program to plan a secure and economical hourly generation schedule for the daily/weekly-ahead market. The objective of security-constrained daily hydrothermal generation scheduling is to determine an optimum schedule of generating units for minimizing the cost of supplying energy and ancillary services with considering network security constraints. The problem formulation includes dynamic ramp-rate constraints for generation schedules and reserve activation, and minimum up-time and down-time of conventional units. Of particular interest in this study are considering more practical constraints and rigorous modeling of thermal and hydro units such as prohibited operating zones and valve loading effects. Furthermore, for the hydro plants, multi performance curve with spillage and time delay between reservoirs are considered. To assess the efficiency and powerful performance of mentioned method, a typical case study based on modified IEEE-118 bus system is investigated and the results are compared to each other in different test system.

Contents

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1. Introduction

The electric energy securance issue has been getting noticed in the governments in whole of the world. Especially in recent years that the energy consuming has been increased due to industry deploy and dramatic use of electric devices instead of mechanic types. Recently, many of governments are decided to invest in the new resources particularly sustainable energy resources to providing the required energy. The main reasons of this plan are summarized as (a) as to being competed the fossil energy resources and raising its price in international energy market and (b) the legislation of environmental laws such as stated in the "Low Carbon Transition Plan", July 2009, the governments are obliged to reduce the Carbon emission to 80% by 2050 [1]. Videlicet, wind turbine generators (WTG) will supply 20% of the US power demand by 2030 [2] and European Union planned for 20% power generation from renewable energy sources by 2020 [3]. But, the increment in penetration of wind power plants on power systems poses well-documented technical challenges for the existing power systems because of uncertainty production characteristic. Especially, in modern systems so-called Smart Grids, it is necessary to consider the unit commitment (UC) and economic dispatch incorporating wind farms generation.

Therefore, uncertainty of renewable energies must be included as an aim function in system scheming daily and weekly means an economic and secure schematization which consists of the hydro and thermal units incorporating wind power plants. Daily Hydrothermal Generation Scheduling (DHGS) is a unit commitment and economic dispatch among hydro and thermal units during a scheduling period of time for supplying the demand in minimum total cost. Also to obtain the realistic results, the practical constraints related to thermal plants, hydroelectric system and electrical power system (i.e. satisfying power system demand) should be investigated. On the other hand, ISO coordinates market activities for satisfying the hourly load demand, limited fuel and other resources, environmental constraints, and transmission security requirements [4–6].

Several literatures are studied on methods to estimation of accurate wind speed and consequent power output of wind farms. These investigations have been based on such foundations as fuzzy logic [7], neural networks [8], and time series [9]. In this paper, the time series model of Auto Regressive Integrated Moving Average (ARIMA) has been used for modeling of wind power generation uncertainty [10].

Providing the Security-Constrained Hydrothermal Coordination (SCHTC) with the lowest cost is the nonlinear problem with multiple minima. There are some techniques such as Lagrangian Relaxation (LR) [4], Dynamic Programming (DP) [5], Mixed Integer Programming (MIP) [11], Benders Decomposition (BD) [12] and various intelligent techniques [13–15] to find the best solution for a goal function with complex and nonlinear characteristics and heavy equality and inequality constraints. In this paper, the MIP approach is applied for solving the SCHTC with volatile wind power generation problem which many of the practical constraints for detailed modeling of the all of type units are considered. Ref. [16] develops a two-stage stochastic mixed-quadratic programming problem has been proposed a new modeling of the optimal unit commitment and sale bid to the day-ahead market, and the optimal economic dispatch of the bilateral contracts for all the thermal and combined cycle units. This paper has been used from real data of a Spanish generation company and market.

In electricity market, the ISO has an important role in management of the whole network by possession of the commit and dispatch of all energy resources based to required load with meeting of security constraints and minimum cost [17–19]. Actually, the ISO determine an optimum schedule of generation units with the standard market design (SMD) according to security-constrained unit commitment (SCUC), for minimizing the cost [20]. This is done while in several studies the GENCO effort to scheduling the generation of units to obtain the maximum profit [21]. In this paper the unit commitment and scheduling of system units (hydro, thermal and wind) is done and analyzed from ISO's viewpoint for having the minimum cost.

Finally, in this paper the both thermal and hydro subsystems are considered in planning of ISO against of [20–23] that studied them separately without considering of security constraints. Also limitations of the ramp rate, frequent switching, frequent cycling of hydro units in daily operations according to mechanics problems and costs related to start-up and wear and tear of those, and prohibited operating zones (POZs) in thermal units are considered in UC and ED [24,25]. In addition to prior mentions, the hydro and thermal units operating characteristics such as valve point loading and minimum up and down time constraints are added to the proposed model for more precision although may be caused to a higher nonlinear, non-smooth and non-convex function [24]. Also to conducting the simulation, the load is not constant and has been considered as a variable parameter. The load uncertainty is modeled based on the error of load prediction and needed scenarios for solving the problem are generated by the Monte Carlo Simulation (MCS) method and roulette wheel mechanism [26,27].

The remaining sections of this paper are organized as follows. In Section 2, the stochastic model of hybrid wind-hydrothermal scheduling is formulated as a 0/1 mixed-integer linear programming problem. The modeling approaches used in this paper to represent the load and wind power generation uncertainties are described in Section 3. Obtained results from case studies with detailed discussion are presented in Section 4, and at the end the conclusions are drawn in Section 5.

2. MIP formulation of security-constrained wind hydrothermal coordination

Mathematically security-constrained wind hydrothermal coordination is a decision problem with an objective to be minimized with respect to a series of prevailing equality and inequality constraints. There are many parameters, equality and inequality constrains for reality optimum scheduling of units in power system. These limitations must be considered in the goal function

Nomenclature

Indices

I	thermal unit index
J	hydro unit index
wf	wind farm index
t	time interval (hour) index
s	scenario index
u	uncertain parameter index

Constants

η	conversion factor equal to 3.6×10^{-3}(Hm^3 s/m^3 h) (1 Hm^3=10^6 m^3)
Θ	number of periods of the planning horizon (24 h)
$\underline{\theta}(j,t)$	minimum water discharge of unit j at hour t (m^3/s)
$\overline{\theta}(j,t)$	maximum water discharge of unit j at hour t (m^3/s)
τ_{ij}	time delay between reservoir of plant i and reservoir of plant j (h)
A_i	shut down cost of unit i ($)
A_j	start-up cost of unit j ($)
$b_n(i)$	slope of block n of fuel cost curve of unit i($/MWh)
$b_n(j)$	slope of the volume block n of the reservoir associated to unit j (m^3/s/Hm^3)
$b_n^k(j)$	slope of the block n of the performance curve of k unit j (MW/m^3/s)
$be_n(i)$	slope of segment n in emission curve of unit i
$DT(i)$	minimum down time of unit i (h)
e_i	valve loading coefficient
$e_{\min}(i)$	minimum emission generation of unit i (lbs)
EGR	emission group consists of SO_2, NO_X
$E(p_{n-1}^u(i))$	emission generation of $(n-1)$ th upper limit in emission curve of unit i
$EM_{\max}(i)$	maximum emission of unit i (lbs)
$EM_{\max}(gr)$	maximum emission of group (lbs)
f_i	valve loading coefficient
FGR	fuel group consists of coal, gas and oil
$F_{\min}(i)$	minimum fuel consumption of unit i (Mbtu)
$F_{\max}(i)$	maximum fuel consumption of unit i (Mbtu)
$F_{\min}(gr)$	minimum fuel consumption of group (Mbtu)
$F_{\max}(gr)$	maximum fuel consumption of group (Mbtu)
$F(p_{n-1}^u(i))$	cost of generation of $(n-1)$th upper limit in fuel cost of unit i
$F(j,t,s)$	forecasted natural water inflow of the reservoir associated to plant j in period t (Hm^3/h)
$K^{\lambda}(i)$	Cost of the λth discrete interval of the start-up cost of unit i ($/h)
$I^0(i)$	initial status of unit i (0/1)
L	number of variable head
M	number of prohibited operation zones
NS	number of scenario after scenario reduction
$p(s)$	probability of scenario s
$p^{\text{norm}}(s)$	normalized probability of selected scenario s
$MSR(i)$	maximum sustained ramp rate (MW/min)
MU	maximum number of units that can be on at the same time
NB	number of bilateral contract
NES	number of discrete intervals of the start-up emission function
NE	number of discrete intervals of emission function
NL	number of blocks of the piecewise linearization of the variable cost function
$p_m^b(t)$	power capacity of bilateral contract m at hour t (MW)
$p_{min}(i)$	minimum power output of unit i (MW)
$p_{max}(i)$	maximum power output of unit i (MW)
$\underline{p}_n(j)$	minimum power output of plant j for performance curve n(MW)
$\overline{p}(j)$	capacity of plant j (MW)
$p_n^d(i)$	lower limit of nth prohibited zone of unit i (MW)
$p_{n-1}^u(i)$	upper limit of $(n-1)$ th prohibited zone of unit i (MW)
$\underline{Q}(j)$	minimum water discharge of hydro plant j if is on (m^3/s)
$\overline{Q}_n(j)$	maximum water discharge of block n of plant j (Hm^3)
$QSC(i)$	quick start capacity of unit i (MW)
$RDL_n(i)$	ramp down limit for block n (MW)
$RUL_n(i)$	ramp up limit for block n (MW)
$s^0(i)$	time periods of unit i has been shut-down at the beginning of the planning horizon (h)
$\overline{s}(j)$	maximum spillage of unit j (m^3)
$s_{max}(i)$	maximum hour unit i can be off (h)
$SUE(i)$	emission generated by unit i when started up (lbs)
$SDE(i)$	emission generated by unit i when shut down (lbs)
$SDF(i)$	fuel consumption of unit i when shut down (Mbtu)
$SD(i)$	shut-down ramp rate limit of unit i (MW/h)
$SU(i)$	start-up ramp rate limit of unit i (MW/h)
$UT(i)$	minimum up time of unit i (h)
$U^0(i)$	time periods of unit i have been on-line at the beginning of the planning horizon (h)
$v_0(j)$	minimum content of the reservoir associated to plant j (Hm^3)
$v^0(j)$	reservoir content at the beginning of the study time (Hm^3)
$v^{\Theta}(j)$	reservoir content at the end of the study time (Hm^3)
$v_n(j)$	maximum content of the reservoir j associated to nth variable head (Hm^3)

Variables

$\delta_n(i,t)$	generation of block n of fuel cost curve of unit i at hour t
$\gamma(i,t)$	dummy variable (h)
$\psi_n(i,t)$	generation of block n of unit i at hour t of valve point loadings curve
$\psi_n(j,t)$	volume block n for the reservoir of hydro plant j at hour t (MW)
$B(i,t)$	start-up cost of unit i at hour t ($)
$b_n(i)$	slope of power block n of fuel cost curve of unit i ($/MWh)
$b_n^l(j)$	slope of the block n of the performance curve l of hydro plant j (MW/m^3/s)
$c(i,t)$	valve point loadings cost of unit i at hour t ($)
$F(i,t)$	fuel cost of unit i at hour t ($)
$N_d(i,t)$	non-spinning reserve of a unit i at hour t for bid on spot market when unit is off (MW)
$N_d(j,t)$	non-spinning reserve of a unit j at hour t for bid on spot market when unit is off (MW)
$N_u(i,t)$	non-spinning reserve of a unit i at hour t for bid on spot market when unit is on (MW)
$N_u(j,t)$	non-spinning reserve of a unit j at hour t for bid on spot market when unit is on (MW)
$p(i,t)$	real power generation of unit i at hour t (MW)
$p_{\min}(i,t,s), p_{\max}(i,t,s)$	lower and upper limit of real power generation of unit i at hour t (MW)
$p(j,t)$	real power generation of unit j at hour t (MW)

$\underline{p}(j,t,s), \overline{p}(j,t,s)$ lower and upper limit of real power generation of unit j at hour t (MW)
$p^s(t)$ power for bid on spot market at hour t (MW)
$Q(j,t)$ water discharge of unit j at hour t (m^3/s)
$q_n(j,t)$ water discharge of block n of unit j at hour t(m^3/s)
$R(i,t)$ spinning reserve of a unit i at hour t for bid on spot market (MW)
$R(j,t)$ spinning reserve of a unit j at hour t for bid on spot market (MW)
$RDL(p(i,t))$ ramping down limit of unit i at hour t (MW)
$RUL(p(i,t))$ ramping up limit of unit i at hour t (MW)
$s(i,t)$ time periods that unit i has been shut-down at hour t (h)
$s(j,t)$ spillage of the reservoir associated to unit j at hour t (m^3/s)
$v(j,t)$ water content of the reservoir associated to plant unit j at hour t (Hm^3)

Binary variables

$\beta_n(i,t,s)$ 1 if block n of fuel cost curve of unit i at hour t selected
$\beta_n(j,t,s)$ 1 if variable head n+1 of unit j at hour t selected
$\chi_n(i,t,s)$ 1 if power output of unit i at hour t has exceeded block n
$h_n(j,t,s)$ 1 if the water discharge of unit j at hour t has exceeded block n
$I(i,t,s)$ 1 if unit i is on-line at hour t
$I(j,t,s)$ 1 if hydro plant j is on-line at hour t
$I_d(i,t,s)$ 1 if unit i at hour t provide non-spinning reserve when unit is off.
$Id_n(i,t,s)$ 1 if block n of ramping down limit curve of unit i at hour t selected
$Iu_n(i,t,s)$ 1 if block n of ramping up limit curve of unit i at hour t selected
$w^{\lambda}(i,t,s)$ 1 if unit i is started-up at the beginning of hour t and it has been offline for λ hours
$y(i,t,s)$ 1 if unit i is started-up at the beginning of hour t
$y(j,t,s)$ 1 if unit j is started-up at the beginning of hour t
$z(i,t,s)$ 1 if unit i is shut-down at the beginning of hour t
$z(j,t,s)$ 1 if unit j is shut-down at the beginning of hour t

Sets

G set of indices of the group units
I set of thermal units
J set of hydro units
WF wind farms
N set of indices of the blocks of the piecewise linearization of the unit performance curve.
T set of indices of the periods of the market time horizon
S scenario numbers
SP stochastic parameters (*wf* indicates wind farms)
i,p,q,r sets of ARIMA family model
Λ set of the discrete intervals of the start-up cost function for thermal units
Ω_j set of upstream reservoirs of plant j.
N time number of wind power generation time series.

as security constraints included the transmission flow and bus voltage constraints or the start-up limitations caused extra investment. In this section, the objective function and its different parts of simulation is explained clearly.

2.1. Objective function

In this work, the suggested objective function to determine the optimal planning of coordination of wind, hydro and thermal units over scenarios caused minimum cost is described as (1). It is necessary to remind that the load in this paper is varied constantly.

$$Cost^{total} = \sum_{s} p^{norm}(s).\cos\ t(s)$$

$$\cos\ t(s) = \sum_{t\in T}\left\{\sum_{i\in I}[F(i,t,s) + A_i Z(i,t,s) + B(i,t,s) + C(i,t,s)] + \sum_{j\in J} A_j y(j,t,s)\right\} \tag{1}$$

The last term of variable cost function of each scenario represents the corresponding cost of hydro units regarding their start-up cost over the given period [28]. While the first term shows thermal operating cost including fuel, shutdown, startup costs and valve point loadings cost. The operating costs of wind units are assumed to be zero. The list of symbols is presented in the Nomenclature section.

When minimizing the total cost in power systems, the total generation of hydro, wind and thermal plants should be equal to the total system demand plus the transmission network loss. Due to simplicity, the network loss is not considered in this paper. This equation is given by

$$\sum_{i\in I} p(i,t,s) + \sum_{j\in J} p(j,t,s) + \sum_{wf\in WF} p(wf,t,s) = \mathrm{P}_{D,t} \qquad \forall t\in \mathrm{T},\ \forall s\in \mathrm{S} \tag{2}$$

2.2. Cascaded-hydro units' model

According to previous sections, the hydro power plants have the start-up limitation. Because of the unnecessary commitments, loss of water during start-up period, wear and tear of the windings and mechanical equipment, the start-up limitation must be considered in planning. In this regard, the relation among generated power, water discharge, and multi performance curves of hydro power plant is shown in Fig. 1. The proposed model takes into account head dependent reservoirs with MIP formulations as well as hydro plants connected both in parallel and series shown in Fig. 2. The number of the heads for power plants is considered to be L in the following formulations represented in Fig. 1.

Performance curves based on the water volume can be given by (3)–(6) show that the volume of each hydro power plant must be bigger than the minimum content of that hydro plant. Eqs. (4) and (5) determine the right head proportional to volume. Combination

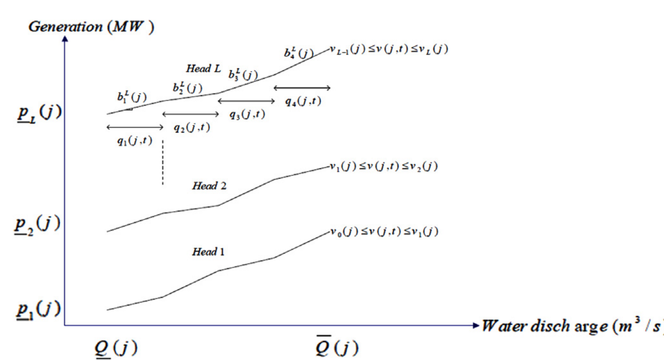

Fig. 1. Three-dimensional piecewise linear non-concave unit performance curve for hydro plant j at hour t.

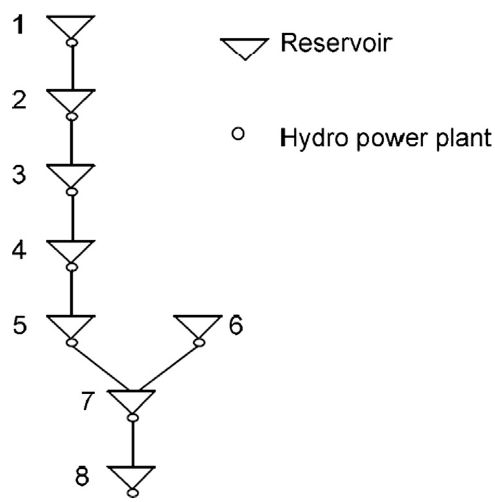

Fig. 2. Hydraulic topology of the river basin.

of 0–1 for these binary variables is prevented by Eq. (6). $\beta_n\ (j,t,s)$ equals to 1 when $(n+1)$th head is used or water volume of the reservoir is greater than $V_n(j)$. In other words, these equations choose the right curve for head according to the content level.

$$v(j,t,s) \geq v_0(j) \quad \forall j \in J, \forall t \in T, \forall s \in S \tag{3}$$

$$v(j,t,s) \leq v_L(j)\beta_{L-1}(j,t,s) + \sum_{n=2}^{L} v_{n-1}(j)[\beta_{n-2}(j,t,s) - \beta_{n-1}(j,t,s)] \quad \forall j \in J, \forall t \in T, \forall s \in S \tag{4}$$

$$v(j,t,s) \geq v_{L-1}(j)\beta_{L-1}(j,t,s) + \sum_{n=3}^{L} v_{n-2}(j)[\beta_{n-2}(j,t) - \beta_{n-1}(j,t,s)] \quad \forall j \in J, \forall t \in T, \forall s \in S \tag{5}$$

$$\beta_1(j,t,s) \geq \beta_2(j,t,s) \geq \ldots \geq \beta_{L-1}(j,t,s) \qquad \forall j \in J, \forall t \in T, \forall s \in S \tag{6}$$

2.2.1. Piecewise linear formulation of the variable head multi performance curves

In most papers the effect of the variation of the head has been neglected and head is assumed fix. The proposed MILP model take into consider head dependent reservoirs with a piecewise linear approximation. After determination of each unit in this subsection, the linear relationship between the generated powers, the discharged water and variable head for corresponding performance curve can be presented as follows:

$$p(j,t,s) - \underline{p}_k(j)I(j,t,s) - \sum_{n \in N} q_n(j,t,s)b_n^k(j) - \overline{p}(j)\left[(k-1) - \sum_{n=1}^{k=1} \beta_n(j,t,s) + \sum_{n=k}^{L=1} \beta_n(j,t,s)\right] \leq 0$$
$$\forall j \in J, \forall t \in T, \forall s \in S, 1 \leq k \leq L \tag{7}$$

$$p(j,t,s) - \overline{p}_k(j)I(j,t,s) - \sum_{n \in N} q_n(j,t,s)b_n^k(j) + \overline{p}(j)\left[(k-1) - \sum_{n=1}^{k=1} \beta_n(j,t,s) + \sum_{n=k}^{L=1} \beta_n(j,t,s)\right] \geq 0$$
$$\forall j \in J, \forall t \in T, \forall s \in S, 1 \leq k \leq L \tag{8}$$

where $p(j,t,s)$ is the generated power by the hydro unit j at hour t, $P_k(j)$ is the minimum power generation of the head k which is determined by $\beta_n(j,t,s)$. Also, $P(j)$ is the capacity of hydro unit j, and $q_n(j,t,s)$ is the water discharge of the block n. Finally, $b_n{}^k(j)$ is the slope of the block n of the variable head k of hydro unit j.

2.2.2. Water discharge limits

The water discharge limit and initial and final volume and water balance equations same as the equations presented in [22]; however, in the proposed WHTC model the spillage effect is also considered which is inspired by [29].

2.3. Thermal units' model

In this subsection deal with the linearization of all nonlinear equations related to thermal units to represent the linear model for thermal units.

2.3.1. Linear fuel cost function considering POZ

The thermal units have some prohibited operating zone due to steam valve operation or vibration in its shaft bearing and some faults in the machines or their accessories such as pumps or boilers, etc. It has been shown that the input–output curve of thermal units has some valve points. These valve points generate some prohibited zones, so the input–output curve of thermal unit will be discontinuous. The quadratic production cost function can be accurately approximated by a set of piecewise blocks. So, the linear formulation of power generation for the ith thermal unit considering M POZs is modeled as follows:

$$F(i,t,s) = \sum_{n=1}^{M+1} [\beta_n(i,t,s)F(p_{n-1}^u(i)) + b_n(i)\delta_n(i,t,s)] \quad \forall i \in I,\ \forall t \in T, \forall s \in S \tag{9}$$

$$P(i,t,s) = \sum_{n=1}^{M+1} [p_{n-1}^u(i)\beta_n(i,t,s) + \delta_n(i,t,s)] \quad \forall i \in I,\ \forall t \in T, \forall s \in S \tag{10}$$

$$\delta_n(i,t,s) \geq 0 \quad n = 1,2,\ldots,M+1, \forall i \in I,\ \forall t \in T, \forall s \in S \tag{11}$$

$$\delta_n(i,t,s) \leq [p_n^d(i) - p_{n-1}^u(i)]\beta_n(i,t,s) \quad n = 1,2,\ldots,M+1, \forall i \in I,\ \forall t \in T, \forall s \in S \tag{12}$$

$$\sum_{n=1}^{M+1} \beta_n(i,t,s) = I(i,t,s) \qquad \forall i \in I, \forall t \in T, \forall s \in S \tag{13}$$

$$\beta_n(i,t,s) \in \{0,1\} \quad n = 1,2,\ldots,M+1, \forall i \in I,\ \forall t \in T,\ \forall s \in S \tag{14}$$

where, $p_0^u(i) = p_{\min}(i)$ and $p_{M+1}^d(i) = p_{\max(i)}$.

2.3.2. Cost of valve point loadings

In practical, the generators have the multiple valves in steam turbines. The opening and closing of these valves caused to maintain the active power balance. However it adds the ripples in the cost function [30]. To calculate and consider the valve-point effects, sinusoidal functions are added to the quadratic cost functions as follows [31–33]:

$$F_i(P_i) = a_i + b_iP_i + c_iP^2 + abs(e_i \sin(f_i(P_{i\min} - P_i))) \quad \forall i \in I \tag{15}$$

where e_i and f_i are the coefficients of generator ith considering valve point loading effect.

But the added sinus term to cost function cause to having a nonlinear and non-convex function that can be obstacle in MIP model. In this paper a linear formulation is proposed to overcome this problem as shown in Fig. 3.

$$C(i,t,s) = \frac{2f_ie_i}{\pi}\left\{\sqrt{2}\sum_{n=0}^{k_i}[\psi_{4n+1}(i,t,s) - \psi_{4n+4}(i,t,s)] + (2-\sqrt{2})\sum_{n=0}^{k_i}[\psi_{4n+2}(i,t,s) - \psi_{4n+3}(i,t,s)]\right\} \quad \forall i \in I,\ \forall t \in T,\ \forall s \in S \tag{16}$$

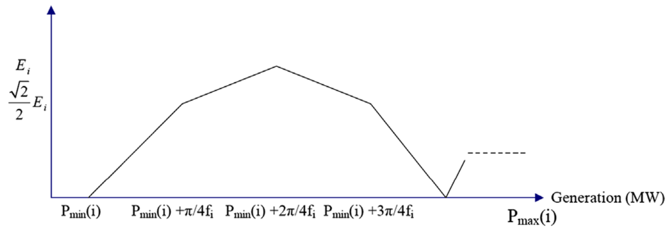

Fig. 3. Linear approximation absolute sinus function valve point loading.

where, ψ_n (i,t,s) is power generated by nth block in sth scenario.

$$p(i,t,s) = p_{\min}(i)I(i,t,s) + \sum_{n=0}^{k_i}\left[\psi_{4n+1}(i,t,s) + \psi_{4n+2}(i,t,s)\right.$$
$$\left. + \psi_{4n+3}(i,t,s) + \psi_{4n+4}(i,t,s)\right] \quad \forall i \in I,\ \forall t \in T, \forall s \in S \tag{17}$$

$$\frac{\pi}{4f_i}\chi_1(i,t,s) \le \psi_1(i,t,s) \le \frac{\pi}{4f_i}I(i,t,s) \quad \forall i \in I, \forall t \in T, \forall s \in S \tag{18}$$

$$\frac{\pi}{4f_i}\chi_n(i,t,s) \le \psi_n(i,t,s) \le \frac{\pi}{4f_i}\chi_{n-1}(i,t,s) \quad \forall i \in I, \forall t \in T, \forall s \in S, n = 2, 3, \ldots, x_i \tag{19}$$

$$\chi_n(i,t,s) \in \{0,1\} \quad \forall i \in I, \forall t \in T, \forall s \in S, n = 1, 2, \ldots, x_i \tag{20}$$

where,

$k_i = floor[f_i(p_{\max}(i) - p_{\min}(i)/\pi)]$ *and* $x_i = floor[4f_i(p_{\max}(i) - p_{\min}(i)/\pi)]$

Constraint (17) states that power output of unit i at hour t is the sum of minimum power output if unit is on, plus the power generated in each block. Constraint (18) limits the power generated in first block, this power should be greater than zero and smaller than or equal to $\pi/4fi$ that is "power length" of each block. In this constraint, *I(i,t,s)* is used ensuring that power generated of first block equal to zero, if unit i is off at hour t. To limit the generated power in each block $\chi_n(i,t,s)$ is introduced in constraints (18)–(20). This binary variable equal one if the generated power of unit i at hour t has exceeded block n.

2.3.3. Dynamic ramping up/down limit

Variations of load have been responded by generators by decreasing and increasing of generating power. But the rate of the power output changing is limited by two constraints. The increasing and decreasing constraint is defined by up and down ramp rate that are specified for each generator. In this work a dynamic ramp rate is used, as the ramp rate is a function of the generating power. Also in this method the M POZ are considered. The formulation related to dynamic ramp rate is given as

$$RUL(p(i,t,s)) = \sum_{n=1}^{M+1} RUL_n(i)\beta_n(i,t,s) \quad \forall i \in I, \forall t \in T, \forall s \in S \tag{21}$$

$$RDL(p(i,t,s)) = \sum_{n=1}^{M+1} RDL_n(i)\beta_n(i,t,s) \quad \forall i \in I, \forall t \in T, \forall s \in S \tag{22}$$

Constraints (21) and (22) indicate dynamic ramp limit with M POZs. The binary variables are used to indicate which operating zone has been selected. Another formulation for dynamic ramp rate is proposed in [34].

2.3.4. Stair-wise formulation of the time-dependent startup cost function

Starting up generating unit costs money in addition to the running cost considered in economic dispatch. This cost is modeled as a nonlinear (exponential) function of the number of hours a unit has been off. In [35,36] two different methods have been suggested for time dependent linearization of this function. In this paper is used of formulation proposed in [35].

2.3.5. Minimum up-time (MUT) and minimum down-time (MDT)

Another major source of complication in system planning is the nonlinear minimum up/down time constraints which has to be checked. In this study a linear formulation for these constraints is represented as follows:

$$\sum_{t=1}^{B(i)} [1 - I(i,t,s)] = 0 \qquad \forall i \in I \tag{23}$$

$$\sum_{\tau=t}^{T_1} I(i,\tau,s) \ge UT(i)y(i,t,s) \quad T_1 = t + UT(i) - 1,$$
$$\forall t = B(i) + 1, \ldots, \Theta - UT(i) + 1 \tag{24}$$

$$\sum_{\tau=t}^{\Theta} [I(i,\tau,s) - y(i,t,s)] \ge 0 \quad \forall i \in I, \forall t = \Theta - UT_i + 2, \ldots, \Theta \tag{25}$$

$$\sum_{t=1}^{C(i)} I(i,t,s) = 0 \quad \forall i \in I \tag{26}$$

$$\sum_{\tau=t}^{T_2} [1 - I(i,\tau,s)] \ge DT(i)\, Z_i(t,s) \quad T_2 = t + DT(i) - 1,$$
$$\forall t = C(i) + 1, \ldots, \Theta - DT(i) + 1 \tag{27}$$

$$\sum_{\tau=t}^{\Theta} [1 - I(i,\tau,s) - z(i,t,s)] \ge 0 \quad \forall i \in I, \forall t = \Theta - DT(i) + 2, \ldots, \Theta \tag{28}$$

Once the operation of a unit begins, the operational status should be maintained as least for a certain time (MUT). Eq. (23) determines the initial status of units so unit will be on if $B(i)$ is less than $UT\,(i)$. The MUT limit for consecutive periods and for the last hours is satisfied by (24) and (25) respectively. Similarly, if the operation of a unit is terminated, the un-operational status should be maintained at least for a certain time (MDT) [36]. Constraints (26)–(28) enforce the MDT limit.

The detailed formulation of other hydro units constraints such as initial and final volume [22], water balance [29] and operating services [37] considered in the problem, are represented in the mentioned references.

2.4. Security constraints

The security constraints required in security-constrained wind hydrothermal coordination problem, are obtained based on DC power flow model due to it has more accuracy than the linear power flow model. In this model the physical flow in a grid is controlled by Kirchoff's current law (KCL) and Kirchoff's voltage law (KVL), while in linear power flow model only the KCL is considered. In DC power flow model, the transmission constraints are considered as linear constraints. So the practical constraints related to thermal plants, hydroelectric system are expressed by piecewise linear approximation, therefore the security-constrained WHTC is a Mixed Integer Linear Programming (MILP) problem. The related formulation to the DC power flow is given as

$$\sum_{i=1}^{NG_b} P_{it} - P_{bt}^{D} = \sum_{l=1}^{L_b} P_{lt} \quad \forall b, \forall t \in T \tag{29}$$

$$F_{lt} = \frac{1}{X_l}(\delta_{ls} - \delta_{lr}) \quad \forall b, \forall t \in T \tag{30}$$

Transmission flow limits in the base case:

$$-F_{lt}^{\max} \le F_{lt} \le F_{lt}^{\max} \quad \forall l, \forall t \in T \tag{31}$$

3. Wind power generation and demand forecast uncertainty

One of the most important issues considered recently by researchers of restructure power systems widely, is the uncertainty in operation of power systems. Uncertainties such as uncertainty due to system load prediction error or uncertainty due to unexpected departure of network equipment (i.e. production units and lines). One another these uncertainties related to the error in prediction of the accurate value of wind farms output, especially which penetration of this energy resource type in power grids are increasing.

3.1. Wind power uncertainty modeling

The wind power is a non-predictable complete accurately. This future is rooted from the wind nature. Therefore the primary problem for incorporating wind power plants in power system is the uncertainty of them that decrease the reliability of grid. Several investigations have looked at the prediction of wind speed for use in determining the available wind power [7,8].

In literatures that study on the wind farms uncertainty, the wind power plant is modeled on two method, wind speed-based approaches [38–42], and wind power-based approach [10]. In the wind speed-based approaches, the wind speed must be measured accurately and the generating power be calculated with model of wind-turbine that usually is unavailable. While in power-based approach does not require the model of wind farm due to the output of them is measured and recorded directly, so the whole of wind power data with its details is available. Also in this method the error of prediction is smaller due to the amount of generated power by a wind-turbine is proportional by the cube of wind speed, so an small error (ε) in the wind prediction produce a more big error (ε^3) in expected power output than when the wind power is measured directly.

Although there are other methods for consideration of volatility of the wind power generation like as Monte Carlo simulation, and Latin hypercube sampling method [43], in this paper, inspired by [44], an Auto-Regressive Integrated Moving Average (ARIMA) process is used to model wind power generation uncertainty directly as a wind power-based stochastic approach. In the following, the ARIMA process is described clearly.

3.1.1. ARIMA model of wind power

An ARIMA (p,d,q) model of the non-stationary random process $W(t)$ is depicted as [10]:

$$\left(1-\sum_{i=1}^{p}\varphi_i D^i\right)(a-D)^r W(t)=\theta_0+\left(1-\sum_{i=1}^{q}\theta_i D^i\right)n(t) \tag{32}$$

where $\{\varphi_i\}$ is the Auto-Regressive (AR) coefficients; $\{\theta_i\}$ is the moving average (MA) coefficients; $n(t)$ is a white Gaussian process with zero mean and variance σ_n^2; the parameter θ_0 refers to the deterministic trend term when $r>0$.

The coefficients of the ARIMA model can be estimated by different approaches, e.g. the Yule–Walker estimator, the least square estimator, and the maximum likelihood estimator [45]. For specification of the ARIMA's family there are two model selection criteria in various stochastic analyses that the Akaike's Information Criterion (AIC) [45] and Bayesian Information Criterion (BIC) is more common than other types. The ARIMA(0,1,1) model that is appropriate for the wind power time series is described as Eq. (33).

$$(1-D)W_0(t)=(1-\theta_1 D)a(t)$$

$$WP(t)=W_0^2(t)\quad for\quad \mathrm{t}=1,\ldots,\mathrm{N} \tag{33}$$

In this paper, the ARIMA(0,1,1) are used in wind-hydrothermal coordination for generating of different wind power generation scenarios and modeling of random trend of the wind farm.

The relation between the input wind power and the output electric power relies on several factors, such as the efficiencies of generator, wind rotor, gearbox, and inverter, depending on what kind of turbine under investigated. For a generic wind turbine, some researchers [46,47] used a simplified model to characterize the relation between the wind power generation (WPG) and wind speed [48]:

$$w=0\quad for\quad v<v_i\quad and\quad v>v_o \tag{34}$$

$$w=w_r\frac{v-v_r}{v_r-v_i}\quad for\quad v_i<v<v_o \tag{35}$$

$$w=w_r\quad for\quad \mathrm{v_r}<v<v_o \tag{36}$$

Eqs. (34)–(36) show the power output of wind power plants is limited by wind speed, while the ARIMA model cannot consider these limitations. Thus these margins has been considered for output wind farms and added to the standard ARIMA model to include the upper and lower bounds of the WPG as follows:

$$W_0(t)=\begin{cases} W_{\max} & W_0(t)>W_{\max} \\ W_0(t) & W_{\min}<W_0(t)<W_{\max} \\ W_{\min} & W_0(t)<W_{\min} \end{cases} \tag{37}$$

where $W_{\max}$ and $W_{\min}$ denote the upper and lower bounds of the square root of the wind power output, respectively. The block diagram of the limited ARIMA(0,1,1) is shown in Fig. 4.

3.2. Load uncertainty modeling

In this paper, the load uncertainty is considered as the error of load prediction. Thus, the probability distribution function of load prediction error must be derived based on the records of earlier loads. It should be mentioned; here it is assumed that the load forecasting process as one of the tasks of the ISO, before the implementation market has been done. Another noticeable point is that, considering each of the loads connected to the network as an independent variable will be caused to increasing of the number of random variables and the problem will be more complex. To solve this problem, the network load is considered as a random variable. It is natural that for getting the value of each of the loads connected to the network, it is sufficient to be divided based on the ratio of each bus load to the total load in the base state. Fig. 5 is an example of the probability distribution function of the prediction error of network load and with its discretization.

As is seen in Fig. 5, seven different load intervals centered mean error of zero (base state) is considered, so that distance of between the different levels of load forecast error equal to the standard deviation (SD) of load prediction error.

The important issue is how to model the random load level as a random variable. To implement this is used from the roulette wheel mechanism [49,50]. For this aim, first is applied the possibility of different levels of load prediction error based on the unit load so that the total probability is equal to one. Then, the distance between range [0,1] is covered based on the normal

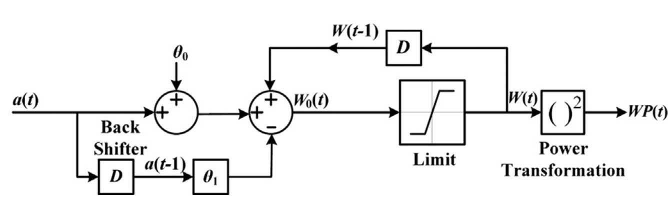

Fig. 4. Block diagrams of ARIMA(0,1,1)-type wind power time series models [21].

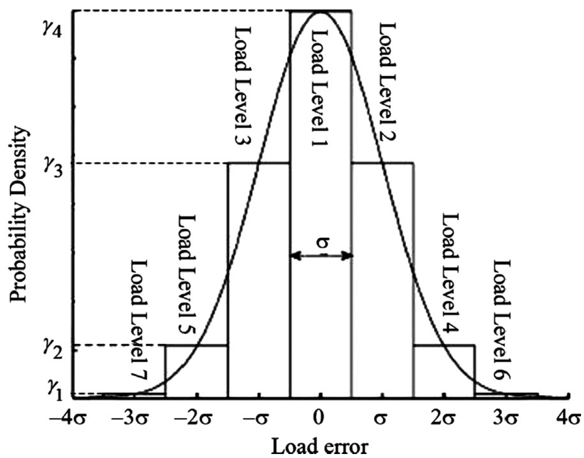

Fig. 5. Typical discretization of the probability distribution of the load error [26,27].

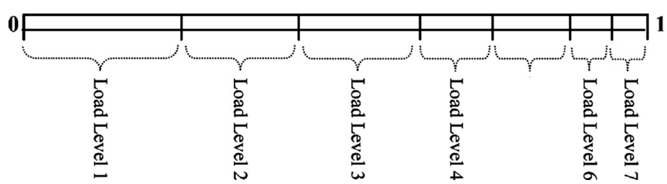

Fig. 6. Roulette wheel mechanism for the normalized probabilities of the load forecast levels.

probability of forecast error levels of load. Naturally, whatever the probability of prediction error levels of load is more; it will occupy more space of the roulette wheel. To clarify this mechanism, the roulette wheel in Fig. 6 is illustrated.

After forming of the roulette wheel, a random number in the range [0,1] is generated. The number produced will be in specified ranges on the roulette wheel are associated with different levels of load forecast error, this means that the load level related to this interval are selected for the desired scenario. Thus, for generating of each new scenario, the roulette wheel mechanism will be used to model the behavior of random load.

A higher number of scenarios results in a better modeling of uncertainties but with the cost of higher computation burden. Accordingly, after the production scenarios, it may be a very low probability of some scenarios and will only cause to increasing of time and volume calculations. Therefore, it is necessary to eliminate the Low-value scenarios from the set of produced scenarios and decrease the number of scenarios. In this paper, the strategy adopted for this purpose is the removing scenarios with less than probability and the similar scenarios [51]. This reduction process results a model of uncertainties with more less accuracy and negligible error with the cost of higher computation burden.

3.3. Scenario aggregation

The idea of stochastic security-constrained WHTC is to construct or sample possible options for uncertain circumstances, solve the deterministic security-constrained wind hydrothermal coordination problem for the possible options, and select a good combination of the outcomes to represent the stochastic solution. Two methods are usually considered for scenario aggregation (the combination of the scenario outcomes) of the stochastic security-constrained wind hydrothermal coordination [52]: (1) using minimum value of the random variables over the scenarios and (2) applying weighted-average (expected value) of variables over the all scenarios. Using minimum value of daily operating cost may lead to pseudo-scheduling with optimistic operating costs in the planning horizon. Because it may be, minimum daily operating cost be related to the scenario with minimum occurrence probability and has a significant difference ratio to other scenarios determined daily operating cost of problem. So, can be inferred that using of first method is a very conservative method and not economical. While in second method videlicet weighted-average or expected value, scenarios with more probability will have a more contribution on specification of final value of daily operating cost. It seems which second method is more reasonable of economic view point. For this reason, in this paper the second method is used for aggregation of different scenarios result paper to determine total daily operating cost of problem.

So, in the proposed stochastic optimization framework, the later method (expected value) is considered. In this way, the solutions obtained from different scenarios are aggregated based on the probability laws to yield a single solution, describing the most probable outcome of the power system based on the evaluated scenarios, considered as the result of the proposed stochastic security-constrained wind hydrothermal coordination framework.

As stated, the MCS method is implemented to simulate random characteristics of power systems load and then the scenario aggregation technology is used to convert the stochastic variables of the stochastic security-constrained wind hydrothermal coordination problem into deterministic ones. A major advantage of scenario aggregation technique is that not only individual scenarios become simple to interpret but also the underlying problem structure is preserved. After running the proposed security-constrained wind hydrothermal coordination scheme for the accepted scenarios resulted from the scenario reduction, the results are aggregated according to the probability of scenarios to get the expected results of the formulation of hybrid wind-hydrothermal scheduling considering uncertainties.

The aggregation is done for the scenario dependent decision variables $I(i,t,s)$, $I(j,t,s)$, $F(i,t,s)$, $p(i,t,s)$, $p(j,t,s)$,$R(i,t,s)$, $R(j,t,s)$ of the optimization problem. The aggregation is done as

$$f = \sum_{s=1}^{NS} p_s^{norm} . f_s \quad \forall s \in S \tag{38}$$

where, f is the variable that is aggregated and f_s is the variable value at scenario s. It is noted that the objective function of the proposed formulation for security-constrained WHTC problem in Eq. (1) is also an aggregation of the objective function values of the scenarios.

In the present paper, two main categories of power system uncertainties (load and wind power uncertainties) are considered in security-constrained wind hydrothermal coordination program that execute by ISO to plan a secure and economical hybrid wind-hydrothermal generation scheduling.

When the number of variation and constraint increased by increasing the size of system, the solution time will increased and sometimes solver cannot solve the problem, but there are several method to overcome this obstacle. Benders decomposition approach [53] is useful method for this situation, also parallel processing may be used for solving this problem, for solving method with non linear constraint, linearization maybe handsome.

4. Case studies

A modified IEEE 118-bus test system is used to test the proposed algorithm for the security constrained day-ahead wind-hydrothermal power scheduling [54]. In addition to hydro and thermal units, two wind farms are assumed which are supervised financially under ISO operating scheme. Random behavior of wind power generation is

Table 1
Results of the scenarios of the stochastic security-constrained WHTC framework.

No.	Scenario no.	Normalized probability	Total wind power (MW)	Daily operating cost ($)
1	1	0.788	1572.175	755704
2	26	0.030	1238.43	839811
3	28	0.013	1639.317	802221
4	39	0.010	1557.42	742289
5	40	0.008	1393.175	861473
6	45	0.009	1466.166	761167
7	52	0.010	1257.439	865732
8	56	0.015	1497.414	867398
9	78	0.005	1305.838	801530
10	79	0.033	1551.793	731831
11	82	0.013	1250.692	854589
12	87	0.003	1565.795	770844
13	97	0.006	1445.347	775077
14	101	0.009	1353.77	850058
15	105	0.024	1504.765	777797
16	133	0.006	1504.793	789590
17	145	0.005	1408.149	804971
18	158	0.001	1640.804	826181
19	164	0.006	1542.076	765741
20	194	0.006	1232.111	895407

modeled by ARIMA(0,1,1) time series model as described in Section 3.1. Two wind farms are separately modeled to simulate correlation concerns of the stochastic wind power behavior in different areas of the network. Auto and cross correlation coefficients related to two applied wind farms are considered as Appendix I. As mentioned in Section 3, the proposed MIP model of security-constrained wind hydrothermal coordination includes both uncertainties of wind power and load. The practical constraints of thermal and hydro generation units that detailed their modeling are mentioned in Section 2 and additional system-wide constraints such as fuel constraints and emission limits [36,38,55] and spinning and operating reserve requirements [56] are considered in the stochastic optimization framework.

The proposed model is implemented on a Pentium IV, 3 GHz with 1GB RAM using MILP solver CPLEX 9.0 in the GAMS environment [57].

With the use of ARIMA method for modeling the stochastic behavior of wind power generation and roulette wheel mechanism to model uncertainty of load, 200 scenarios, including daily wind power time series and daily load profiles, are generated. It imposes a high computational burden to solve the security-constrained WHTC problem for all of these scenarios. So, the set of generated scenarios (200 wind power generation scenarios/ daily load profile) is reduced using the scenario reduction technique. The generated similar scenarios and scenarios with probability lower than 0.003 are discarded. Number of remaining scenarios after scenario reduction is equal to 20, which results in 200/20 = 10 filtering ratio. So, the scenario reduction technique significantly reduces the computation burden of the proposed stochastic security constrained WHTC framework. At the same time, the most probable and dissimilar scenarios are retained while maintaining a good approximation of the uncertain behavior of these uncertainty resources. For the remaining set of scenarios, the proposed stochastic MILP model of security-constrained wind hydrothermal coordination is run. Selected scenarios, their normalized probability and total daily power generation of wind farms (generated power by WF1 and WF2) are presented in Table 1.

Case 1. Security constrained wind-hydrothermal coordination

In state that security constraints are considered, the minimum and maximum daily operating cost are related to scenario 10 and scenario 20 with 731831$ and 895407.38 $ respectively. The commitment schedules for these scenarios are shown in

Table 2
Scenario 10: WHTC with security.

	Daily operating cost:731830.98 $ Hours (0–24)
1–3	100000000000000000000000
4	111111111111111111111111
5	111111111111111111111110
6	100000000000000000000000
7	111111111111111110000000
8–10	100000000000000000000000
11	111111111111111111111111
12–18	100000000000000000000000
19	111111111111111111111110
20–21	111111111111111111111111
22–23	100000000000000000000000
24–25	111111111111111111111111
26	100000000000000000000000
27–29	111111111111111111111111
30–38	100000000000000000000000
39	111111111111100000000000
40	110000000000000000000000
41–43	100000000000000000000000
44–45	111111111111111111111111
46–51	100000000000000000000000
52	111111111111100000000000
53–54	100000000000000000000000
Hydro1	111111111111111111111110
Hydro2	111111111111111110000000
Hydro3	111111111111111111111110
Hydro4	111111111111111111111110
Hydro5	111111111111111111111110
Hydro6	111100000000000111111100
Hydro7	111111111111111111111110
Hydro8	111111111111111111111111

Table 3
Scenario 20: WHTC with security.

	Daily operating cost:895407.39 $ Hours (0–24)
1	100000000000000000000000
2–3	100000000000000000011111
4–5	111111111111111111111111
6	100000000000000000000000
7	100000000000000000001111
8–10	100000000000000000000000
11	111111111111111111111111
12–18	100000000000000000000000
19–21	111111111111111111111111
22–23	100000000000000000000000
24–25	111111111111111111111111
26	100000000000000000000000
27–29	111111111111111111111111
30–35	100000000000000000000000
36	100000000000000000001111
37–33	100000000000000000000000
39	111100000000000000000000
40	111111111111111111111111
41–42	100000000000000000000000
43	110000000000000000000000
44	111100000000000000000000
45	111111111111111111111111
46–51	100000000000000000000000
52	111111111111111111111111
53–54	100000000000000000000000
Hydro1	111100111111111111111110
Hydro2	111111111111111111111110
Hydro3	111100111111111111111110
Hydro4	111111111111111111111010
Hydro5	111111111111111111111111
Hydro6	100000001000000001111110
Hydro7	1000001101110111100101011
Hydro8	111111111111111111111111

Tables 2 and 3, in which 1 and 0 represent ON/OFF states of units at different hours, and hour 0 represents the initial condition.

According to simulation of scenario 10 and 20, the following results can be obtained:

In scenario 10, the thermal units 2 and 3 which have the high production cost is remained off on all period planning. While in scenario 20, both these units in the final of the day hours (from hour 20 to 24) have been forced to turn on and connected to the grid.

In scenario 10, the thermal plant 40 is not committed at hour 2–24, while in scenario 20 this plant is committed. In scenario 10, the thermal plant 44 is ON at total of 24 h while in scenario 20 it is ON only at hour 1–3. The expensive units of plant 52 is committed at hour 1–13 in scenario 10 while it will be ON at total of 24 h in scenario 20. Also the expensive plant 7 and 39 has been ON more hours in scenario 10 than scenario 20. So expensive plant 7 is connected to grid from hour 1 to 16 while in scenario 20 it has been committed only at hour 21–24.

The hydro units 6 and 7 in scenario 10 are committed more hours than scenario 20.

The whole generating power of hydro and thermal plants in the scenarios 10 and 20 are 15107.94/54218.871 MW and 14656.002/62380.987 MW respectively. As can be seen, in scenario with lower production cost, i.e. scenario 10 the amount of hydro plants production is more. Also the ratio of the hydro generating power to total of power generated with hydro and thermal plants is 21.79% and 19.02% in scenario 10 and 20 respectively.

In scenario 10, the thermal plants generate the 54218.871 MW power in all period of time and the average of generating power with those is 2259.119 MW. While the maximum generating power of thermal power is 3369.614 MW in hour 15. It is noteworthy that variation of thermal plants generating power is less compared with variation of hydro plants generating power given in next paragraph ((3369.614–2259.119)/2259.119 = 49.16%). The reason of these low variations is the limitation of thermal plants power variations and due to this constraint, the thermal units do not follow the rapid load variations.

In scenario 10, the hydro units in all period of time produce the 15107.94 MW that its average is the 629.497 MW at each hour. The minimum generating power at hour 14 is 104.415 MW and the maximum of hydro units generating power at hour 15 is 1393.809 MW. The variations of hydro units generating power are very high and pursue the load variations in instantaneous market. Also the amount of whole SO_2 and NOX gases produced during 24 h has been 80697.95 and 41878.83 in scenario 10 and 101391.11 and 50755.54 in scenario 20 respectively. This indicates that despite production cost in scenario 10 is less than scenario 20, the amount of pollution gases generation is less too. Also it should be noted that the minimum pollution gases (SO_2 and NOX) generation related to scenario 10.

Table 4
Scenario 1: WHTC without security.

	Daily operating cost: 698636.98$ Hours (0–24)
1–4	1000000000000000000000000
5	1111111111111111111111111
6–10	1000000000000000000000000
11	1111111111111111111111111
12–19	1000000000000000000000000
20–21	1111111111111111111111111
22–23	1000000000000000000000000
24–25	1111111111111111111111111
26	1000000000000000000000000
27–29	1111111111111111111111111
30–38	1000000000000000000000000
39–40	1111111111111111111111111
41–44	1000000000000000000000000
45	1111111111111111111111111
46–54	1000000000000000000000000
Hydro1	1111111111111111111111110
Hydro2	1111111111111111111111110
Hydro3	1111111111111111111111110
Hydro4	1111111111111111111111110
Hydro5	1111111111111111111111111
Hydro6	1000000000000000111110000
Hydro7	1111111111111111111110000
Hydro8	1111111111111111111111111

Table 5
Congested/uncongested status of violated lines in scenario 1 (with minimum cost) of Case 2.

	Hours (0–24)
L37	0000000000000000011010000
L41	0000000000000000000110000
L124	0000000010001001011100000
L126	0000000000001001000100000
L127	0000000000001000000000000
L134	0000000010001001011110000
L136	0000000010001001011110000
L137	0000000000001001000100000
L138	0000000000001000000100000
L139	0000000000001000000100000
L142	0000000000000000111110000

Case 2. Wind-hydrothermal coordination without considering of security constraints

Again each 20 scenarios have been simulated without considering security constraints and their power production cost has been compared with each other. It can be seen that with not considering of the security constraints the minimum and maximum of production cost daily related to the scenario 1 and 20 with 698609.36 $ and 811174.28 $ respectively. The commitment schedule of scenario 1 is shown in Table 4. Also it is obvious which considering of security constraints will be caused to increasing the power production cost daily compared to when they are neglected. The main reason is that if prior due to satisfying security constraints some cheap units cannot be ON, now in this state can be ON. With comparing of scenario 1 (scenario with lowest cost related to state without considering of the security constraints) and scenario 10 (scenario with lowest cost related to state with considering of the security constraints), it is seen that the both inexpensive units 4 and 5 are committed in scenario 10, while in scenario 1 only unit 5 maintains its ON state. Also it is obtained that the both expensive thermal units 7 and 52 in scenario 10 to supplying load and satisfying of security constraints has been forced to be ON at hour 1–16 and hour 1–13 respectively, whereas in scenario 1 these unit all 24 h has not been committed. Compared scenario 1 with scenario 10, thermal unit 40 that was OFF in all of 24 h has been ON and unit 39 is committed at the more hours to compensate for the reduced supply for decommitting of thermal units 19, 44 and 52 and to satisfy physical constraints in scenario 1.

With comparing of scenario 20 (scenario with highest cost) with and without considering of the security constraints, it is seen that the economical unit 4 and both inexpensive units 19 and 52 had been forced to be ON over a day to supplying load and satisfying of security constraints, have been OFF. Instead of these decommitted units, inexpensive unit 10 that was OFF before will be ON at total of 24 h. Also expensive thermal units 2, 3 and 7 and units 34 and 44 that were ON only in the first or last hours of the

Table 6
Congested/uncongested status of violated lines in scenario 20 (with maximum cost) of Case 2.

	Hours (0–24)
L30	0000000000000000000111000
L37	0000000100000000000101010
L41	1000001111000000001101111
L54	0000000000000000000001000
L124	0000001101000000000001011
L126	0000000001000000000000000
L127	0000000000000000000000000
L134	0000001101000000000101010
L136	0000001101000000000101010
L137	0000000000000000000000000
L138	0000000000000000000000000
L139	0000000000000000000000000
L142	0000000000000000001101110

Table 7
Scenarios with minimum/maximum daily operating cost ($) in 3 cases.

	With security constraints			**Without security constraints**		
	Case 1	**Case 2**	**Case 3**	**Case 1**	**Case 2**	**Case 3**
Scenario 10	731831	-----	------	------	------	------
Scenario 20	895407.38	----		-----	811174.28	------
Scenario 1	------	------		------	698609.36	------
Scenario 15	----	-----	991005.67	------		------

Table 8
Aggregated results of the stochastic security-constrained WHTC framework in 3 cases.

	Case 1	**Case 2**	**Case 3**
Daily operating cost ($)	788596.71	730831.36	1086309.34

day, and also without considering security constraints during these hours they have been OFF and decommitted over a day. For compensating of reduced supply due to decommitting these 5 units, unit 39 that was ON only in first 3 h of day it have been forced to be ON over a day to supplying load.

When in this case, we calculate the WHTC solution by excluding transmission and voltage constraints, transmission flow violations in scenario 1 and scenario 20 occur in different lines and hours. Tables 5 and 6 show all of transmission flow violations on congested lines for these scenarios without considering security constraints, in which 1 and 0 represent congested/uncongested status of lines at different hours, and hour 0 represents the initial condition.

Results show that branch 41 is very congested. This branch has 80 MW of capacity and that is not sufficient to transmit less expensive generation from the right-hand side of the system to the left-hand side and the its' transmission flow in Case 3 is near or at the capacity limit at hours 1, 2, 8, 9, 10, 11, 12, 14, 15, 16, 18 and 19. Also scenario 20 has less congested line than scenario 1, for example congested lines 127, 137, 138,139 in scenario 1 do not have any violated flow in scenario 20.

Case 3. Evaluation of effect of hydro units on the security-constrained WHTC problem

Once again, each 20 scenarios have been simulated and investigated. But this time with eliminating of hydro plants from problem and then their power production cost that related to the thermal and wind units, are compared with each other. In this case the minimum and maximum production cost daily are related to the scenario 15 with 991005.67 $ and scenario 20 with 1204288.30 $ respectively. Because of not produce power by hydro units which are inexpensive units, it can be seen that production cost in each scenario is higher than two previous cases included hydro units. For quick reference, the three case tests are briefly described in Table 7. Also, the aggregated results of the stochastic security-constrained wind hydrothermal coordination framework, according to the scenario aggregation procedure, are given in Table 8. Using the proposed stochastic framework, all 20 accepted scenarios contribute into determining the security-constrained wind hydrothermal coordination results according to their probability values.

5. Conclusion

In this paper, the thorough and comprehensive MIP formulations for solving security-constrained wind hydrothermal coordination problem at day-ahead are proposed. The objective is to minimize the daily operating cost of ISO. The proposed framework consists of many practical constraints such as prohibited operating zones, valve loading effects, crew constraints, dynamic ramp rate, and fuel and emission limitations for thermal units. Furthermore, for the hydro plants, multi performance curve with spillage and time delay between reservoirs are considered. We also consider transmission network constraints. The main feature of the proposed framework refers to the linear nature of the formulations which is very important for application of the model in the large scale and the real size power system. Therefore, the proposed scheme is practical to generate appropriate information for ISOs. Roulette wheel mechanism and Monte Carlo Simulation (MCS) are employed for random scenario generation wherein the stochastic optimization problem is converted into its respective deterministic equivalents. Results of the implementing the proposed model show that the solution time of the problem is rationale. The research work under way in order to reduce the computational burden due to increasing the problem size, two approaches (and their combinations) can be taken. These are the use of decomposition approaches such as benders decomposition and parallel computing used for each scenario.

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Appendix A

Auto and cross correlation coefficients related to two implemented wind farms [10]:

$$\theta_1 = \begin{pmatrix} \theta_{11} & \theta_{12} \\ \theta_{21} & \theta_{22} \end{pmatrix} = \begin{pmatrix} -0.15 & -0.04 \\ -0.44 & 0.22 \end{pmatrix}$$

$$\theta_1 = \begin{pmatrix} \theta_{0,1} \\ \theta_{0,2} \end{pmatrix} = \begin{pmatrix} 0.008 \\ 0.007 \end{pmatrix}$$

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